Post implementation review of dispatchable demand

Final report

3 July 2018

Market Performance

Executive summary

In 2014 the Electricity Authority (Authority) introduced a dispatchable demand scheme (the scheme). Mechanisms to allow participants who purchase electricity from the wholesale market to benefit from demand reductions was one of the matters the Government required the Authority to consider under section 42 of the Electricity Industry Act 2010. Dispatchable demand (DD) was one such mechanism developed by the Authority. The scheme allows users to bid their load into the market, similar to generators' offers, and benefit from having more control over their electricity costs. Most submissions to the DD consultation process supported the Authority's decision to introduce DD. The major electricity users group (MEUG) submitted that 'it is unlikely there will be no purchasers that will participate'.

Norske Skog Tasman (NST) has so far been the only company to participate in the scheme. NST is one of the country's biggest energy users, using about 500GWh of electricity annually. Under the scheme, the system operator automatically dispatches the load NST bids when forecast prices reach the firm's bid price. NST's entire load is available for dispatch at the two grid exit points (GXPs) it purchases at.

In deciding to introduce the scheme, the Authority considered a quantitative cost-benefit analysis based on three different scenarios of uptake of the scheme. Two main factors drove the benefits:

1. better short-term production and consumption decisions and better long-term investment decisions from better pricing; and
2. more price responsive demand (attracted by constrained on and constrained off payments).

The one-off costs were largely the costs to the system operator of implementing the proposal and supporting its operation. The ongoing costs were those for the dispatch-capable load station owner relating to the loss of operational flexibility.

Overall, we find the scheme:

1. resulted in final prices being around $2/MWh lower on average (than simulated counterfactual prices) over the 175 trading periods when NST was dispatched off. Taking the average over all periods (not just dispatched off periods), prices were around 0.7 cents/MWh lower on average with DD
2. may have assisted NST in co-ordinating demand and Interruptible Load (IL) provision
3. has not attracted other users. Potential participants we talked to said that the benefits of price certainty and constrained on and off payments did not outweigh the perceived costs of participating. The perceived costs include:
    - a lack of control over production processes
    - compliance costs due to the complexity of the scheme
    - concern about what impact load curtailment and the duration of load curtailment might have on production processes.

Our analysis shows that:

1. NST was dispatched off (that is, told to consume less than their total bid quantity) for a total of 568 trading periods. However, for many of these trading periods NST's actual load

varied substantially from the dispatch instruction quantity due to a combination of late bids and binary load.

2. While NST uses the DD scheme to reduce demand over peak periods, its overall demand reduction has remained similar since it took up the scheme.
3. The Code change to bring constrained on and off payments in line with their economic purpose was successful
4. There is no evidence to suggest that yo-yo dispatch (ie, being dispatched up and down) is a problem for NST, given that it can submit nominated non-dispatch bids.
5. There is no evidence that final prices have ‘shadowed’ (that is, increased in line with) DD bid prices, as claimed by NST

As a result of conducting this review, the Authority considers that the scheme so far is unlikely to have accrued benefits over and above its implementation costs, and would be unlikely to do so without further refinement to encourage more participation in the future. One reason for this is low participation.

When considering regulatory changes which require participation in order for public benefits to be realised, the Authority should pay careful attention to participant’s expected private benefits. The private benefits of any scheme need to outweigh the private costs of joining (both perceived and real). In addition, while submitters may give general support for a potential scheme (as they did for the DD scheme), this does not indicate a commitment to participate. For the DD scheme, some submitters created option value by supporting the development of the scheme (with no cost involved for them) even though there was perhaps, in hindsight, little likelihood of them participating in the scheme.

Further enhancements to the DD scheme could improve participation in the near future. However, the Authority considers it more appropriate to prioritise effort into progressing the real-time pricing project. Real-time pricing is expected to deliver greater demand-side participation, as well as a range of other benefits.

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Post-implementation reviews assess the effectiveness of regulatory change

1.1 This paper presents the Authority's post-implementation review of the dispatchable demand scheme (the scheme). The Authority introduced the dispatchable demand (DD) scheme on 15 May 2014. The purpose of a post-implementation review is to evaluate an initiative against its expected outcomes. From the Authority's perspective, this enables learning about how regulatory decisions–or decisions not to regulate–are affecting the sector and whether further policy action is required.

The benefits of the dispatchable demand scheme have not outweighed the costs

1.2 Our view is the scheme so far is unlikely to have accrued benefits over and above its implementation costs, and will most likely require further refinement to increase participation (and greater benefits) in the future.

1.3 Should real-time pricing proceed, we recommend a review of the DD scheme, including how to change the scheme to reduce compliance costs (in terms of complexity of the scheme) and increase flexibility.

2 Background to the DD scheme

The Authority introduced the scheme to promote competition

2.1 DD is an optional regime that allows wholesale electricity purchasers to participate in the spot market in a similar way as generators and therefore respond more efficiently to wholesale market conditions. The one-off implementation cost—of which the majority was the system operator's costs—was $4.65m. The Authority introduced the scheme on 15 May 2014 with subsequent changes implemented on 1 December 2015 and 3 November 2016. While most submissions to the consultation process supported introducing the scheme, NST is currently the only participant. NST took up DD on 20 November 2014.

2.2 The Authority implemented DD to:

(a) promote competition in the wholesale market by enabling purchasers to compete with generators to set the price

(b) promote the efficient operation of the wholesale market by improving the quality of information used to produce final prices

(c) promote the reliable supply of electricity to consumers and the efficient operation of the industry by making existing demand response more certain.

2.3 Before the Authority implemented DD, only generators were able to set the final price. The DD scheme allows consumers to participate in the spot electricity market in much the same way as generators. In this way, the Authority considered the DD scheme to promote the competition limb of the Authority's statutory objective.

2.4 DD also provides financial compensation to purchasers that opt in to the scheme when the difference between the forecast price and the final price mean uneconomic cuts in load. For example, if NST was willing to consume 10 MW of electricity at a price of $99/MWh and the short non-response schedule (NRSS) price was $100/MWh, NST would be dispatched off 10 MW (that is, told to not consume this 10 MW). However, if the final price was actually $98/MWh, and therefore did not justify the reduction in load, NST would have been better off consuming the 10 MW. NST would be paid a constrained off payment of $1/MWh for the 10 MW it didn't consume. This payment compensates for the lost profit it would otherwise have made. The constrained on and constrained off payments are **not** payments for demand response per se. Avoiding consumption during periods of high market prices should continue to fulfil the role of rewarding generation and rationing electricity usage.

DD was intended to address four policy problems

2.5 The Authority's *Dispatchable Demand* consultation paper[1] stated that DD addresses the following four policy problems:

(a) **Uncertainty of reward for response:** purchasers and electricity users facing dynamic prices retain a substantial degree of flexibility to respond on their own terms to price forecasts and indicators, but face a risk that they will:

(i) respond to high price indicators by reducing electricity usage but find that the final price (when published) is low; or

(ii) keep using electricity when price indicators suggest the price will not be high, but find that the final price (when published) is high.

This uncertainty about the reward for price response may inhibit a purchaser's or electricity user's responsiveness to price indicators. It may also inhibit investment that facilitates responsiveness.

(b) **Information in final prices:** The pricing manager could use improved information as an input into the final pricing schedule. In particular, the final pricing schedule could use information from a purchaser's bid provided that the purchaser acts closely in accordance with the bid.

(c) **Resource not being used for security:** Some electricity users have load that is potentially available (both in a technical and economic sense) for the system operator to use to manage security issues (eg, to keep electricity flows on transmission assets within maximum limits). However, that resource is currently not being used in that way.

(d) **Limited incentives for response within a trading period:** Purchasers and electricity users facing dynamic wholesale spot prices have limited incentives to respond to market conditions as they change within a trading period. If a large generator withdraws from the market during a trading period due to technical difficulties, final prices will not reflect that withdrawal (since final price calculations use offers in place at the beginning of the trading period). This means there is little additional incentive for purchasers and electricity users to respond by reducing energy usage for the remainder of the trading period.

[1] Published 13 July 2011 and available here: http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/dispatchable-demand/consultations/#c7563

The scheme was modified before implementation

2.6 Modifications made to the scheme before implementation removed the mechanism for addressing the fourth policy problem listed above. The Authority made these changes to simplify the scheme in light of potential time delays to implementation and increases in estimated costs. The *Modified design of dispatchable demand* consultation paper sets out the modifications to the scheme.[2] Details are contained in section 3 below.

2.7 The original DD proposal also included co-optimisation between dispatch bids for a dispatch-capable load station (DCLS) and offered interruptible load (IL) provided by the same DCLS. The Authority proposed this to provide benefits to some DCLS owners and achieve more efficient use of energy and provision of IL. However, the modified DD proposal reversed this decision. Under the modified design, demand and IL are dispatched from different schedules (IL remains being dispatched from the real time dispatch (RTD) schedule and DD became dispatched from the NRSS). Therefore co-optimisation is not possible. Again, the Authority modified the scheme to make it simpler to implement and decrease development costs.

The scheme was further modified after it was introduced

2.8 The Authority also made changes to the scheme after implementation to address problems with how it operated in practice. It made changes in December 2015 to deal with late bid revisions, and further changes in November 2016 for issues arising during tight market conditions. Details are contained in section 4 below.

Terminology

2.9 **Dispatch-capable load station (DCLS):** This is an electricity-using device or group of electricity-using devices which the system operator has authorised a purchaser to submit dispatch bids for.

2.10 **Dispatched**: the DCLS has received an instruction to consume a specific MW quantity of electricity. This means that the price was less than or equal to at least one bid band.

2.11 **Dispatched off**: the DCLS received an instruction to consume a MW quantity that was lower than its total bid quantity.

2.12 **Nominated dispatch bid**: A bid submitted by a purchaser in relation to a DCLS, where the bid indicates the purchaser wishes the bid to be subject to dispatch by the system operator.

2.13 **Nominated non-dispatch bid**: A bid submitted by a purchaser in relation to a DCLS, where the bid indicates that the purchaser does not wish the bid to be subject to dispatch by the system operator. That is, the DCLS has its dispatchable feature “turned off” for that period.

2.14 **Dispatchable**: The DCLS has submitted a dispatch bid. That is, it has signalled that it is available to be dispatched in that period.

2.15 **Non-response schedule**: Under demand-side bidding and forecasting, the Authority identifies GXPs as either conforming or non-conforming. Purchasers at non-conforming GXPs submit demand bids (nominated bids). The NRSS uses a central forecast for conforming load plus bids from purchasers (the sum of quantities only) for non-

[2] Published 23 July 2013 and available here: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/dispatchable-demand/consultations/#c7563

conforming load. It assumes no demand response to price, except for GXPs with dispatchable demand.

3 The original design was simplified

3.1 The table below summarises the modifications the Authority made to the original DD design (before implementation). The Authority made these changes when subsequent investigation found that the original design would take longer and cost more to implement than initially thought. These modifications have implications for the benefits the scheme can realise, as well as for the costs of implementing the scheme.

Table 1: Differences between the original and the modified design

Original DD design	Modified DD design	Comments
Dispatched from the RTD schedule	Dispatched from the NRSS schedule	Reduced functionality from loss of controlled demand response within each trading period.
Available to purchasers at non-conforming GXPs only	Available to purchasers at all GXPs	Allows for wider participation
DD and IL co-optimised	DD and IL not co-optimised	Loss of functionality due to change in schedule used for dispatch
Dispatch instruction issued via a dedicated communication system	Dispatch notified via the wholesale information trading system (WITS)	Cost saving to purchasers from not having to install a dedicated communication system
All purchasers required to provide SCADA	Smaller purchasers not compelled to provide SCADA for the dispatched load, although where it is already provided it will be used	Cost saving to smaller purchasers because they do not need to install a separate telemetered data system
Compliance continually assessed in real time to a similar standard as that for generators to support system security	Compliance will be assessed on average over the trading period to ensure the integrity of final pricing	Less onerous real-time compliance requirements on purchasers. This feature is not regarded as a security issue by the system operator

4 The scheme has changed since it was introduced

The changes that were implemented in December 2015

4.1 Following the initial implementation of the scheme in May 2014, the Authority identified three problems. These stemmed from a DCLS being able to revise its bid after the system operator produced dispatch instructions. The three problems were:

(a) The formula for calculating constrained on and constrained off payments produced results that were not consistent with the economic purpose of such payments (to encourage efficient compliance with dispatch instructions).

(b) The DCLS may have incurred costs trying to comply with the dispatch instruction that the system operator based on an outdated bid.

(c) There was a potential opportunity for a DCLS to manipulate final prices by making "rogue" late bid revisions.

4.2 The Authority identified that $176,017 was paid in constrained on and constrained off payments to DCLSs from 20 November 2014 to 28 February 2015. However, the amount consistent with the intended purpose of constrained on and constrained off payments was $2,880. This means that $173,137 of the amount paid was not consistent with the intended purpose. This was effectively a wealth transfer from consumers (since purchasers fund constrained on and constrained off payments and pass these payments on to consumers) to DCLSs.

4.3 In response to the problems, the Authority amended Part 13 of the Electricity Industry Participation Code 2010 (Code). If a DCLS revises a nominated dispatch bid for a trading period during the 30 minutes before the start of the trading period, the amendment provides that:

(a) The revised bid must be a nominated non-dispatch bid.

(b) The DCLS is not obliged to comply with a dispatch instruction during that trading period.

(c) No constrained on or constrained off situation arises for that DCLS for that trading period.

4.4 Since the revised bid is a nominated non-dispatch bid, the bid will not determine final prices. This removes the opportunity for the DCLS to manipulate final prices by making late bid revisions. The DCLS will also not incur costs dealing with the scheme because there will be no dispatch instruction to comply with.

4.5 The Authority paper *Dispatchable demand: late bid revisions* sets out what was implemented.[3] Section 6 looks at how these late bids affected the DD scheme and at constrained on and off payments before and after the change.

More changes were made in November 2016

4.6 The Authority subsequently identified three additional problems that could occur when supply conditions are very "tight" – that is, when there is insufficient, or close to insufficient, generation and reserves to meet load and reserve requirements. The

3 Published 8 October 2015 and available here: http://www.ea.govt.nz/development/work-programme/operational-efficiencies/operational-enhancements-to-dispatchable-demand/development/decision-paper-on-dispatchable-demand-late-bid-revisions/

decision paper *Dispatchable demand during tight market conditions*[4] sets these out. The problems were:

(a) Inefficient dispatch could occur for high value dispatch bid bands.

(b) A DCLS could end up setting market prices above marginal system costs.

(c) Large constrained off payments could occur.

4.7 On 3 November 2016 the Authority amended clause 13.13(1) of the Code to require that the price associated with a nominated dispatch bid band must be either:

(a) less than or equal to $15,000/MWh; or

(b) equal to $600,000/MWh or a similarly high value determined by the system operator to ensure the nominated dispatch bid band is dispatched on. Final pricing would never set the price at $600,000/MWh because this value is above the generation deficit constraint violation penalties (CVPs).[5]

4.8 This amendment aimed to address the three problems in 4.6 above by ensuring that during tight market conditions, the system operator deploys lower-cost resources before higher-cost resources.

5 One-hour gate closure appears to have had no effect on DD

5.1 There have been other market developments since the Authority implemented DD. Of these, we consider the revised gate closure period as the most likely change to have impacted the DD scheme. However, our analysis suggests that this change has not had any impact on the DD scheme.

5.2 The Authority introduced a shorter gate closure period—from two hours to one hour—on 29 June 2017. DD participants may not revise their bid after gate closure except where a bona fide physical reason necessitates it. However, if the DD purchaser expects the quantity of electricity it is likely to purchase will differ substantially—by the lesser of 10MW or 10 per cent of the bid quantity—from what it originally bid, it must immediately revise its bid quantities, including within the gate closure period. The DD purchaser cannot revise its bid **price** within the gate closure period.

5.3 The Authority identified that one-hour gate closure should increase the ability of DD participants to take efficient actions in response to changing market circumstances.

5.4 To try to assess the effect of one-hour gate closure, we ran simulations using vSPD excluding the DD scheme (see section 10). We tried to assess whether one-hour gate closure had had any impact on the scheme by evaluating the results of these simulations compared to actual final prices. We compared these prices both before and after the Authority introduced one-hour gate closure.

5.5 The average spot price at both NST nodes increased after one-hour gate closure, both in the no-DD scenario and in final prices. The maximum price at both NST nodes

4 Published September 2016 and available here: http://www.ea.govt.nz/development/work-programme/operational-efficiencies/operational-enhancements-to-dispatchable-demand/

5 If there are insufficient generation and reserve offers to meet load, there will be no physical solution to the optimization for that schedule. Although there is no physical solution, the optimization engine does in fact reach a solution by scheduling virtual (non-physical) resources. The virtual resources have very high costs assigned to them known as constraint violation penalties (CVPs).

decreased after the Authority introduced one-hour gate closure, but it decreased by more in the no-DD scenario. These results suggest that one-hour gate closure has not had an impact on the DD scheme, although the low hydro storage situation in 2017 could have affected this result. We would need more data post one-hour gate closure implementation to make a more definitive conclusion.

6 We considered the way NST has used the scheme

Summary

6.1 We analysed the scheme using bid, dispatch instruction, and price data from 20 November 2014 to 6 December 2017, for the two GXP nodes used for DD by NST. We also ran simulations using vSPD including and excluding the DD scheme as it currently stands, for the same time period. Overall, our analysis finds that:

(a) The scheme resulted in 568 trading periods where NST was dispatched off (that is, told to consume less than their total bid quantity). However, for many of these trading periods the actual load varied substantially in relation to the dispatch instruction quantity. This was due to a combination of late bids (before December 2015), initial difficulties understanding the dispatch-off process, and binary load (ie. load that operates at maximum consumption, or not at all).

(b) DD may have assisted NST in co-ordinating demand and IL provision.

(c) While NST uses the DD scheme to reduce demand over peak periods, its demand reduction has remained similar both before and after it took up the scheme.

(d) The Code change to bring constrained on and off payments in line with their economic purpose was successful.

(e) There is no evidence to suggest that yo-yo dispatch (ie, being dispatched up and down) is a problem for NST, given that it can submit nominated non-dispatch bids.

(f) There is no evidence that final prices have 'shadowed' (ie, increased in line with) DD bid prices

NST uses non-dispatch bids to avoid yo-yo demand

6.2 While the scheme requires the purchaser (NST) to submit a separate nominated bid for the DCLS for every trading period, it may elect to make the nominated bid dispatchable. It can do this by ticking a box on the bid form. The bid is then called a "dispatch bid". The purchaser can make this choice each half hour, and can revise it as part of the normal revision process along with other aspects of the bid. If NST has submitted a nominated non-dispatch bid, this means that the system operator cannot dispatch its load, ie, the DCLS has its dispatchable feature "turned off" for that period.

6.3 The rest of this section looks at how often NST has decided to make its bids dispatch bids.

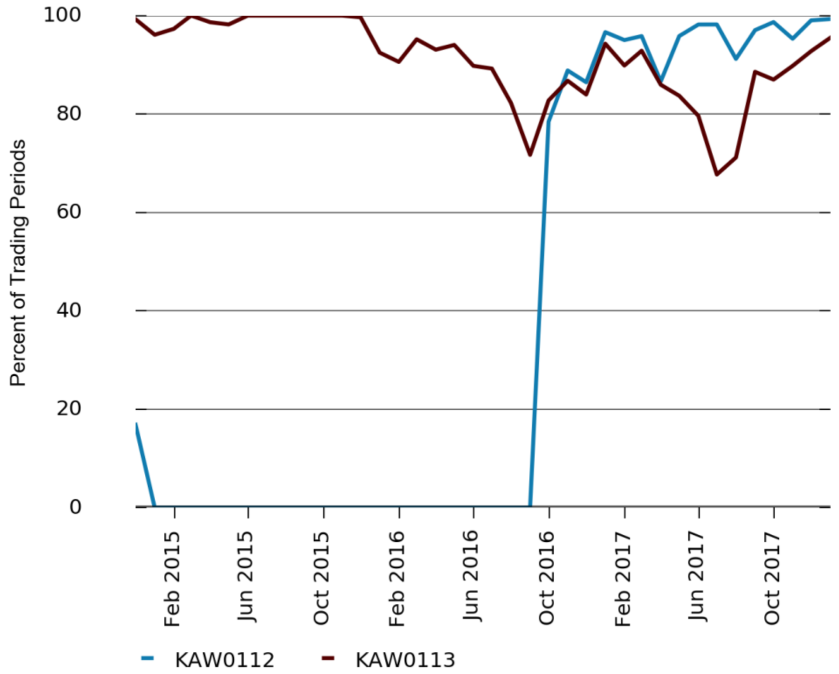
6.4 NST operates two DCLSs, one at the KAW0113 GXP and the other at the KAW0112 GXP, both located in Kawerau in the Bay of Plenty. Over the period 20 November 2014 to 6 December 2017, NST nominated 39.0 per cent and 90.8 per cent of all bids at the KAW0112 and KAW0113 GXP's respectively to be dispatchable.

6.5 However, this overall picture hides changes in behaviour by NST over the period. At the KAW0112 GXP, NST submitted some dispatchable bids during November 2014, but zero trading periods contained a nominated dispatch bid from December 2014 through to August 2016. From September 2016, NST nominated around 80 per cent of all bids to be dispatchable, increasing to around 96 per cent by December 2016. In 2017 the percentage of bids nominated as dispatch bids was above 85 per cent for all months (Figure 1).

6.6 NST drove this behaviour by having load at this node that they did not want to turn off, but also did not want to meter separately. The original compromise was to bid this load at high prices. However, soon after NST implemented this compromise, NST was dispatched off at this node based on an infeasible NRSS price. The constrained-off payment was significant, and hence NST subsequently made the bids at the KAW0112 node non-dispatchable until the Authority found a solution (as discussed in section 2).

6.7 For the KAW0113 GXP, NST nominated more than 90 per cent of all bids as dispatchable bids from November 2014 until April 2016. This decreased to 72 per cent in August 2016 before increasing again to 94 per cent in December 2016. In 2017, the percentage of bids that were dispatchable was around 90 per cent for January and February, before decreasing to a low of 68 per cent in June, followed by 71 per cent in July. In August this percentage increased again to 89 per cent and remained around 90 per cent for the rest of the year.

Figure 1: Per cent of trading periods when bids were nominated dispatch bids



Source: EA

6.8 NST submits non-dispatch bids to ensure that it does not get “yo-yo” demand. That is, after being dispatched off, it may then submit a non-dispatch bid to re-start production smoothly without being dispatched off again. Because of this policy, in the winter months of 2017 (June and July in particular) a lower percentage of bids were dispatchable, since NST was dispatched off more frequently in these months (Figure 6). At the KAW0112 GXP, NST submitted non-dispatch bids for 13 per cent of trading periods immediately after trading periods containing dispatch-off instructions. At the KAW0113 GXP this figure was 55 per cent.

Constrained on and constrained off payments have reduced since the Code change in December 2015

6.9 As section 3 discusses above, before the December 2015 Code change, constrained off and constrained on payments were higher than the amount expected consistent with the economic purpose of such payments.

6.10 Constrained on payments are calculated as follows (and illustrated in Figure 2 below):

$$ConOnAmt = \left(\min\left(Q_{disp}, Q_{rec}\right) - Q_{fp}\right) \times \left(P_f - P_b\right)$$

where

Q_{disp} is the quantity in MWh **dispatched** for the nominated dispatch bid price band in the trading period

Q_{rec} is the **reconciled quantity** provided by the reconciliation manager under clause 15.20C allocated by the clearing manager to the nominated dispatch bid price band in the trading period

Q_{fp} is the quantity in MWh **scheduled** for the nominated dispatch bid price band in the schedule of final prices

P_f is the final price for the trading period at the GXP

P_b is the price bid for the nominated dispatch bid price band for the DCLS that was constrained on

6.11 Similarly for constrained off payments, the calculation is:

$$ConOffAmt = \left(Q_{fp} - \max\left(Q_{disp}, Q_{rec}\right)\right) \times \left(P_b - P_f\right)$$

Figure 2: Constrained on example

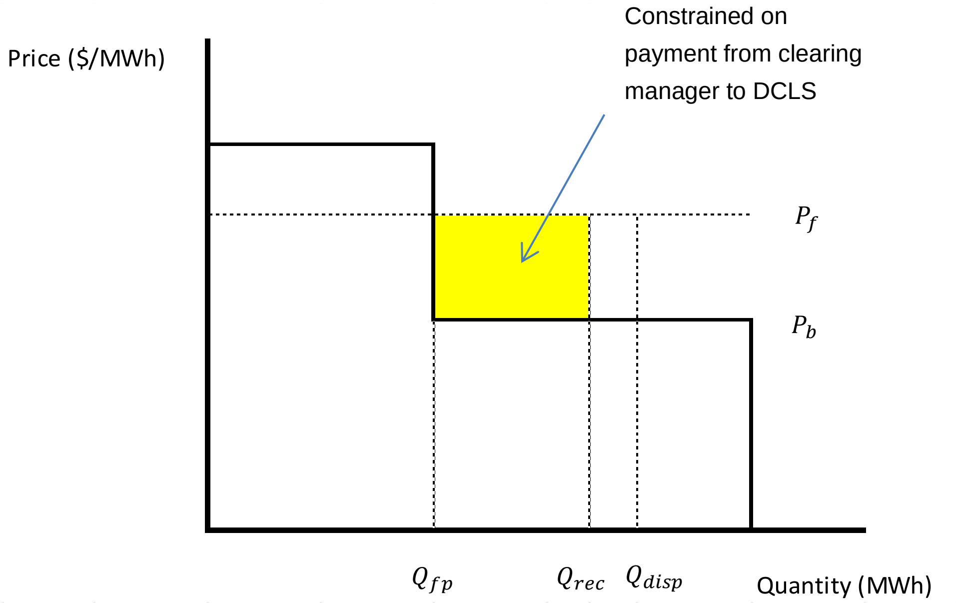
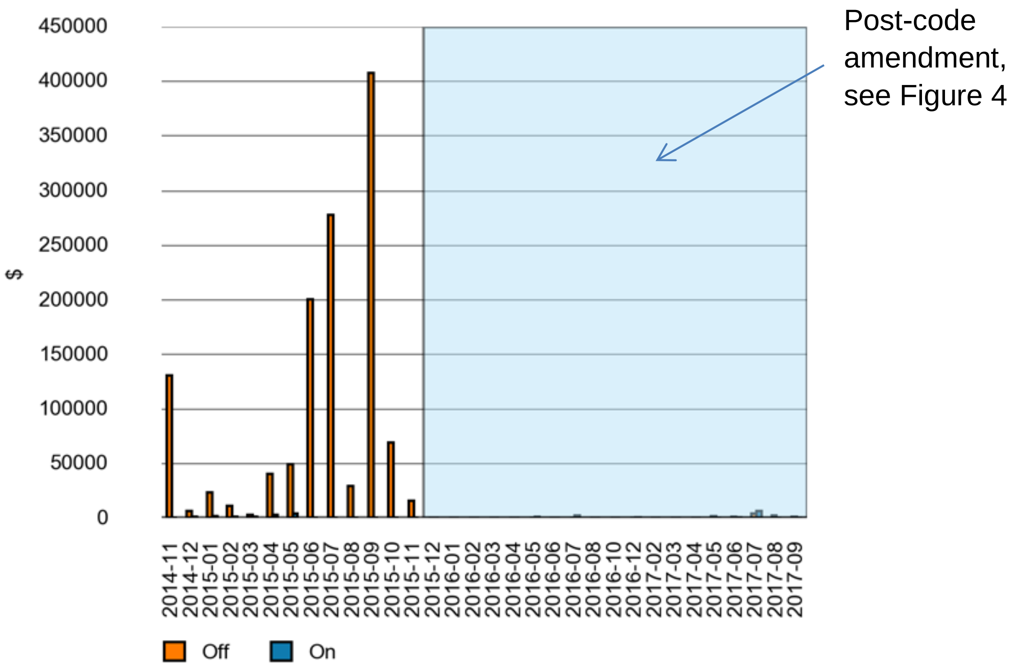


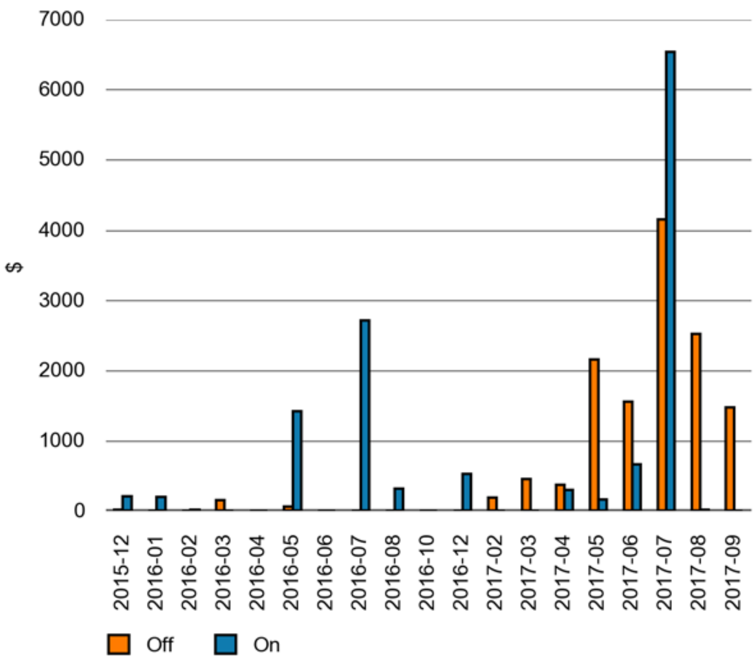
Figure 3: Constrained on and constrained off payments



Source: EA

6.12 Figure 3 shows that before the Code change implemented on 1 December 2015, constrained off payments reached levels of around $400,000 in September 2015 (total for the month).

Figure 4: Constrained on and constrained off payments after the code amendment



Source: EA

6.13 Figure 4 shows constrained on and constrained off payments since the Code change on 1 December 2015. Constrained on payments have decreased substantially compared to the payments made before the Code change.

6.14 Both constrained on and constrained off payments were higher in 2017 than during 2016. This was because NST was dispatched off more frequently in 2017, and the power system was under stress due to low storage in hydro lakes. Final prices are more likely to differ substantially from forecast prices at such times.

NST was dispatched off unsuccessfully more often than successfully

6.15 Under the DD scheme, three steps should occur:

(a) Participants submit bids (price and quantity) before the system operator issues dispatch instructions.

(b) The system operator issues dispatch instructions around 25 minutes before the start of the relevant trading period.

(c) Participants then consume as close as they possibly can to the amount of electricity specified in the dispatch instruction.

6.16 However, historically, problems have occurred with all three of these steps. Until the Code change in December 2015, NST sometimes changed its bid (while still nominating it as dispatchable) after the system operator issued dispatch instructions. Additionally, the system operator has sometimes failed to issue dispatch instructions at all (see https://www.ea.govt.nz/code-and-compliance/compliance/current-investigations/). Finally, NST does not always consume close to the amount specified in the dispatch instructions. This final problem has occurred because of late bids but also sometimes when there was no late bid. This latter case is probably because of the binary nature of the load at the KAW0113 node, but could also have occurred due to problems in understanding the regime. For example NST may have based its consumption on the wrong NRSS price, instead of on the dispatch instruction from WITS.

6.17 Table 2 below shows the different scenarios that could have occurred based on bid, dispatch, and actual quantities. It also shows the number of trading periods between 20 November 2014 and 6 December 2017 when each scenario occurred. For this review, we are interested in potential dispatch-off scenarios (as these periods are when DD has a measurable impact on the market)[6]. That is, when the bid quantity was greater than the dispatch quantity (scenarios C and D). Of these scenarios, we can see there were only 7 trading periods for KAW0112 and 120 trading periods for KAW0113 where the DD scheme worked as it should (scenario C1, highlighted).

6.18 Additionally, there was 1 trading period for KAW0112 and 48 for KAW0113 where NST was dispatched off and consumed an amount nearer to the dispatch quantity than to its bid, despite submitting late bids (scenario C2).

6.19 However, there were 393 trading periods (scenario D, all at the KAW0113 node) where NST was dispatched off, but consumed nearer to its bid quantity than the dispatch

[6] It is possible that DD may have had an impact in periods where the DD bid prices have been higher than final prices by changing generator offer behaviour. However, we consider this is not material to the assessment of benefits in this case.

instruction quantity. Three hundred and fifty four of these trading periods involved late bids. If we:

(a) ignore these late bids

(b) use their previous bid as the final bid instead

(c) assume that dispatch instructions and actual consumption would not have changed,

then 348 of these trading periods would have been counted as scenario A1 (the other 6 would have been scenario D1). That is, there would not have been a dispatch off scenario in those trading periods.

6.20 Additionally, for 89 of the120 trading periods for KAW0113 where the DD scheme worked as it should (scenario C1), NST consumed at least 5 MW away from (more or less than) the dispatch instruction quantity. This is because at this node NST operates two binary loads. The thermomechanical pulp mill consists of two production lines, both of which can only operate at either maximum electricity consumption (around 32 MW) or not at all. There is base load at this node (eg, building services), which consumes around 3 to 8 MW of load when no production lines are running. This means that if the dispatch instruction is less than the bid quantity, NST must turn off at least one production line and reduce load by 32 MW per line (or thereabouts). For example, if NST is dispatched for less than 68 MW (2 production lines running), it would need to run zero, one, or two production lines so the load would be about 4 MW, 36 MW, or 68 MW, regardless of what the dispatch instruction quantity was.

6.21 NST declared this binary load within its application to become a DCLS, and the system operator considered the potential impacts on its principal performance obligations. Load calculated (for each GXP) in the dispatch schedule is immune to DD dispatch non-compliance. Instead, the aggregate load value is derived from the current generation outputs. Therefore, the only impact that DD non-compliance (or non-conforming GXP bid accuracy) has on the dispatch schedule is to distort the distribution of the aggregate load to the GXP level. Since much of the delivery of the principal performance obligations is via the dispatch schedule, this immunity of the schedule to non-compliance issues was a factor in granting NST approval to become a DCLS despite its binary load.

6.22 Since final price calculations are based on NST's bids rather than its actual consumption, we argue that this could be keeping final prices higher than they otherwise could be. This is because NST's bids do not accurately reflect its consumption decisions. Whenever NST consumes less than it indicates in its bids, the final price could be lower. That is, the supply curve would cross the demand curve at a different location if NST's bid curve reflected this consumption decision. For example, if NST was dispatched for 8 MW as in the diagram below, but actually consumed 3 MW, if its bids had reflected this 3 MW consumption (labelled the 'new demand curve' in Figure 5) the price would have been lower.

Figure 5: Reflecting accurate consumption decisions in DD bids

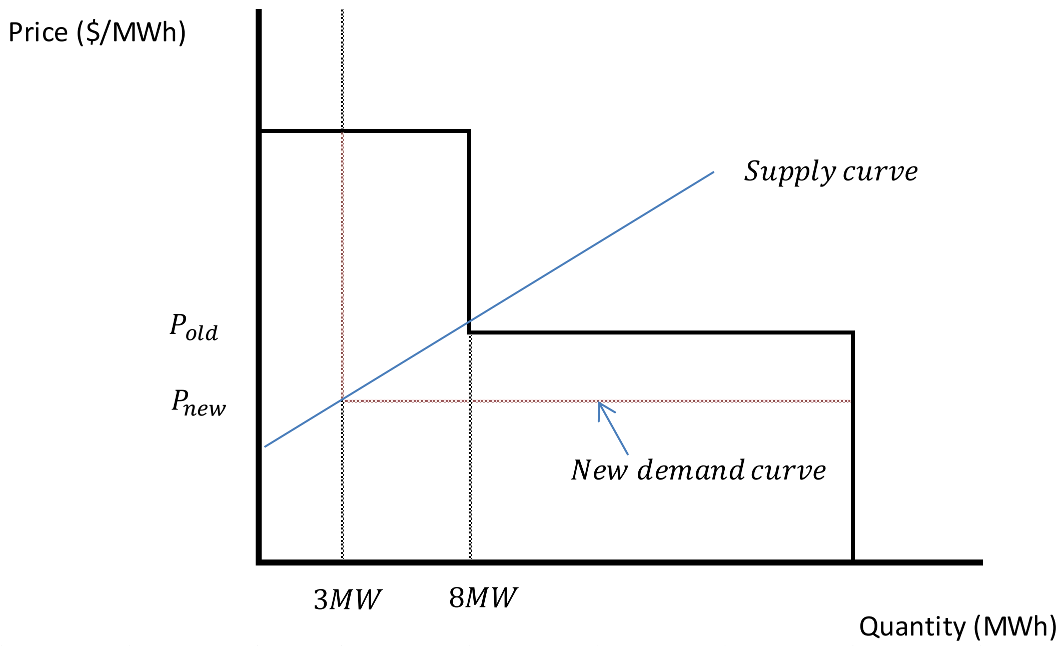


Table 2: Scenarios based on actual quantity consumed (input to SPD)

Scenario Label	Description	Sub-label	Sub-label description	Number of trading periods		Average MW difference between actual quantity and dispatch quantity	
				KAW0112	KAW0113	KAW0112	KAW0113
A	bid = dispatch actual > dispatch	A1	Not a late bid	9974	19548	1.2	2.2
		A2	Late bid	155	409	1.3	2.1
B	bid = dispatch actual <= dispatch	B1	Not a late bid	10021	26799	-1.6	-2.3
		B2	Late bid	119	648	-1.7	-3.9
C	bid > dispatch actual is closer to dispatch than to bid	C1	Not a late bid	7	120	-0.4	-11.1
		C2	Late bid	1	48	2.7	2.0
D	bid > dispatch	D1	Not a late bid	0	39	NA	21.0

Scenario Label	Description	Sub-label	Sub-label description	Number of trading periods		Average MW difference between actual quantity and dispatch quantity	
	actual is closer to bid than to dispatch	D2	Late bid	0	354	NA	26.7
E	bid < dispatch	E1	Not a late bid	0	26*	NA	-20.6
		E2	Late bid	0	450	NA	-21.7
F	No dispatch instructions sent			476	45		

*For all except one of these trading periods NST submitted a bid in the trading period immediately prior (the one exception was a bid made in the previous hour) to the relevant trading period, but outside the 25 minutes we have used here to categorise a late bid. If we change a late bid to include any bid made in the previous trading period, the number of trading periods in scenario D1 becomes 16 and D2 becomes 377. For other scenarios the changes are small.

2017 saw more dispatch off instructions

6.23 There have been 175 trading periods (scenario C) in which NST received an instruction to **not** consume some MW quantity of electricity (ie, was dispatched off), and consumed an amount of electricity closer to the dispatch instruction quantity than to its bid quantity (ideally it would have consumed as close as possible to the dispatch quantity amount whenever it was dispatched off, but this did not always happen for various reasons, as discussed above). Of these, 95 (54 per cent) occurred in 2017. Only 8 of these trading periods included quantity dispatched off at GXP KAW0112. This is because NST submits very high priced bid bands for GXP KAW0112 (before September 2016 it did not make any bids at this GXP dispatchable, except for 3 days in November 2014). Before 2017, the lowest bid band at this GXP was $400. In July 2017 this increased to $600, followed by an increase to $1000 in August 2017.

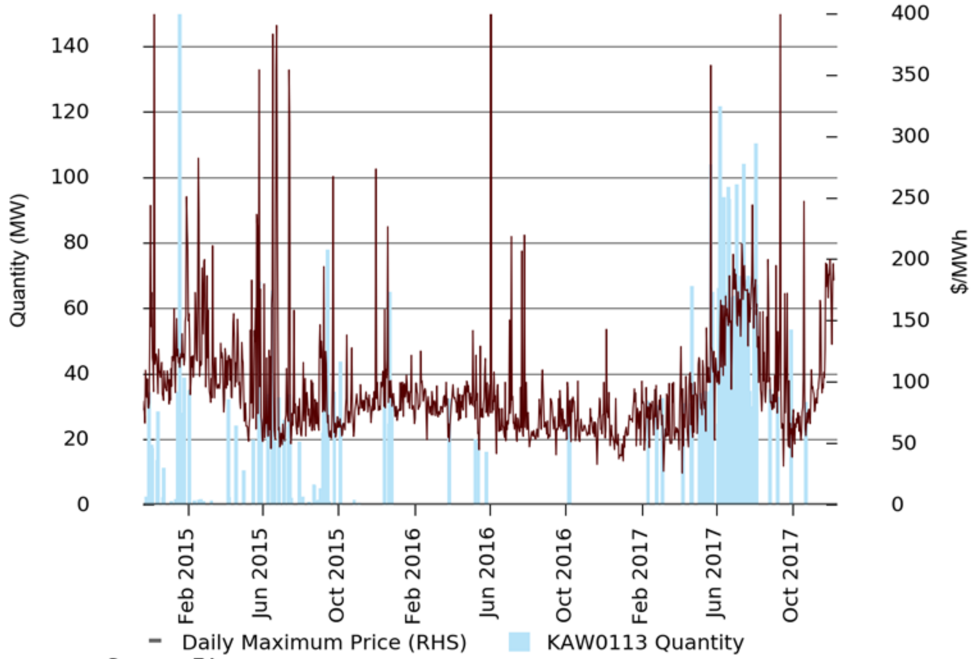
6.24 Figure 6 shows the total quantity **not consumed** at GXP KAW0113 and the daily maximum spot price. It shows that as spot prices increased in 2017, so too did the quantity dispatched off for this node.

6.25 Figure 7 shows total quantity consumed (metered demand) at both NST GXP DCLS's. In June and July 2017 demand at the KAW0113 DCLS decreased, consistent with Figure 6.

6.26 One concern that potential DD participants may have is the potential for yo-yo dispatch. We look at the frequency of yo-yo dispatch that NST has experienced, ie, periods when NST was dispatched on after being dispatched off. As mentioned in paragraph 7.8 above, NST often submit non-dispatch bids in trading periods immediately after trading periods in which they have received dispatch-off instructions (and in those periods consumed nearer to the dispatch quantity than to their bid quantity). For the KAW0113

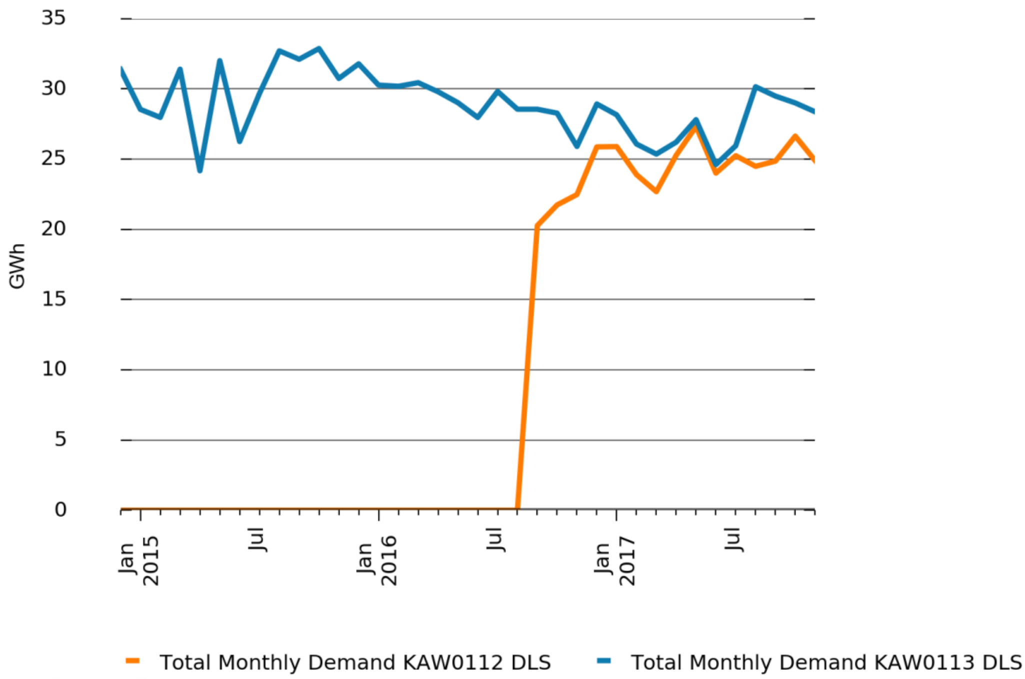
GXP, of the 168 trading periods which followed dispatch-off instructions, NST nominated 93 of them non-dispatch and were dispatched-off again for 12. That means NST experienced yo-yo dispatch instructions for 63 trading periods at this node, ie, for 63 trading periods where NST was dispatched off, it was subsequently dispatched-on.

Figure 6: Quantity not consumed



Source: EA

Figure 7: Total quantity consumed per month



Source: EA

Spot prices don’t appear to be shadowing bid prices

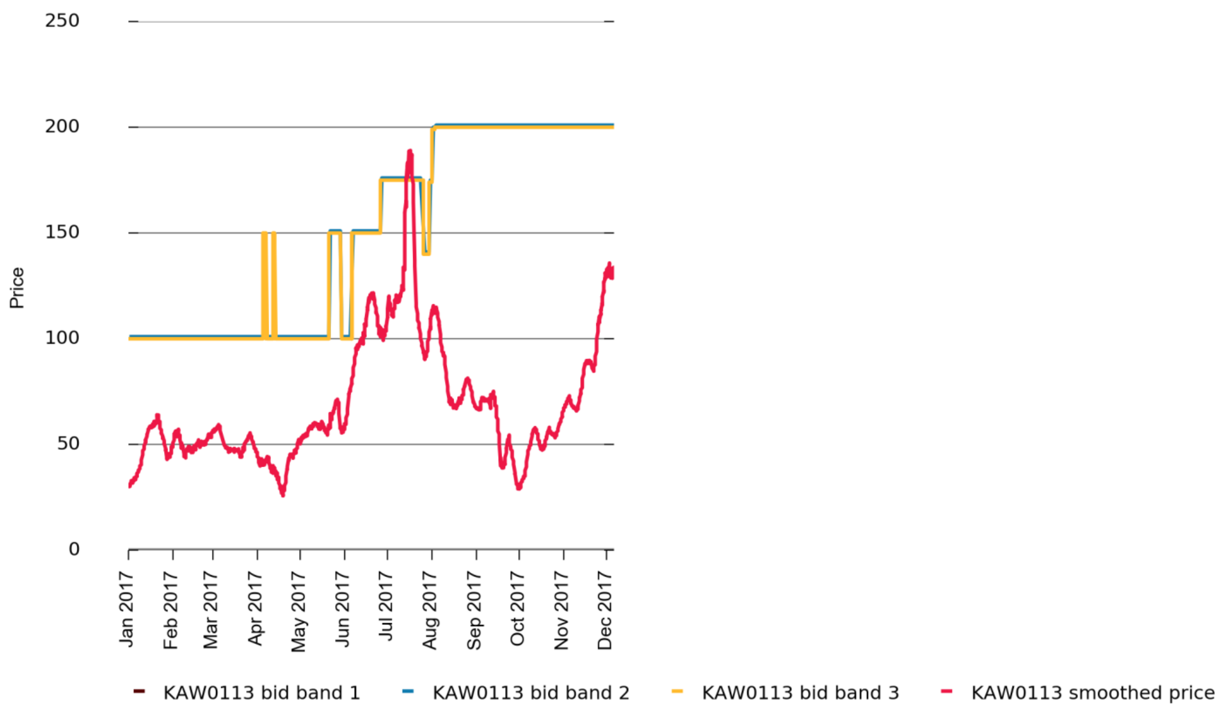
6.27 In periods where the DD bid price is only slightly higher than the spot price, NST is dispatched-off more often.[7] It is also more likely to experience ‘yo-yo’ demand (that is, in some periods being dispatched off and in other periods being dispatched for its full bid quantity) as the spot price could fluctuate around its bid price.

6.28 To avoid this ‘yo-yo’ load occurring, NST may increase its bid price slightly (to avoid being dispatched-off in any period). However, anecdotally the spot price has increased in response. This could happen if the DD bid quantity is the price setter, but should not happen otherwise. NST raised this as a potential issue with the scheme.

6.29 So has the spot price increased when NST has increased its DD bids? This is very difficult to answer. Other factors that affect the price would need to be controlled for and causality established. Distinguishing causality from correlation (or association) would be very difficult in this situation, especially as NST may increase its bid slightly to avoid being dispatched-off, implying that prices are already increasing. However, we can look at what the spot price was doing as bid prices changed, to provide some indication about the answer.

6.30 Figure 8 shows that during the period June 2017 to August 2017 both bid prices and final prices were increasing. This period was a time of high spot prices because of low storage in South Island hydro dams. NST subsequently increased its bid price to $200/MWh while spot prices decreased back to levels seen before the low storage situation. Spot prices then increased again from October, when there were a number of outages and decreasing storage levels in hydro lakes.

Figure 8: Bid price and final price, 2017



Source: Electricity Authority

7 Compared to periods when the bid price is far above the spot price.

6.31 Table 3 below shows the average difference between the minimum DD bid prices that NST has used in 2017 for the KAW0113 node, and the final price. Since the difference is likely to increase when the bid band price is higher, we have also tried to 'normalise' this difference by presenting it as a percentage of the minimum bid band price.

6.32 As a percentage of the minimum bid band price, this difference was lower for bids in the $140-$175 range but higher for the $199 and $200 bids. So while the price was higher when NST made its higher bids, the final price is further away from the bid price in these ranges than for lower bids. This finding, along with the evidence from the chart above, suggest that spot prices have not shadowed bid prices.

Table 3: Difference in final price and bid price, by bid price, 2017

Minimum bid price	Number of Trading Periods	Average difference between final price and minimum bid price ($/MWh)	Average difference as percentage of minimum bid
100	7008	49.54	49%
140	165	28.57	20%
150	1468	58.87	39%
174	114	48.44	28%
175	1456	48.91	28%
199	83	100.39	50%
200	6026	128.10	64%

DD may help NST to co-ordinate IL and demand, despite the changes made to the original design

6.33 One of the benefits discussed in the original consultation paper (see section 10) was of better coordination between electricity usage and Interruptible load (IL) provision. By including DD, SPD should be able to dispatch the optimal combination of electricity usage and IL. However, under the modified DD design, DD is dispatched from the NRSS schedule rather than from the RTD schedule, meaning that SPD cannot co-ordinate the dispatch of DD and IL.

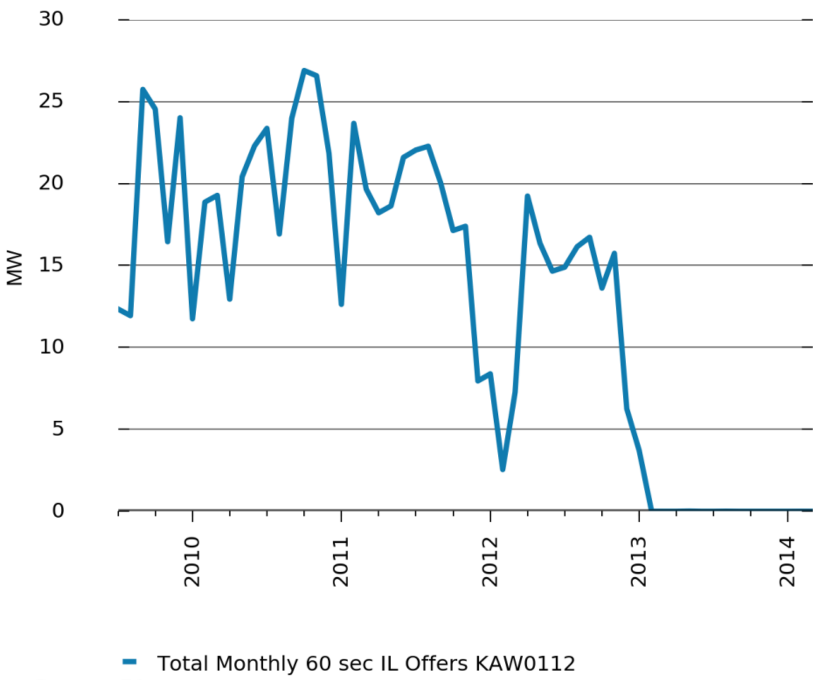
6.34 The modified design still allows a purchaser to participate in both DD and IL markets with the same load. However, it requires the purchaser to ensure that they can deliver both the IL and DD dispatched.

6.35 However, if Real Time Pricing (RTP) (see section 9) becomes a reality, then DD may change again, perhaps to being dispatched from the RTD schedule. This would then mean the system operator could co-optimise IL and DD.

6.36 In our discussion with NST, it said that "Since using DD, it is easier for our operator to coordinate DD; production cuts (load) and interruptible load". Before participating in DD, NST voluntarily reduced load when high prices were forecast. When this happened, sometimes the operator would forget to revise the IL offer accordingly. Now, when NST receives a dispatch instruction to reduce load, the DD alert helps to remind the operator to remove the IL offers and claim a bona fide.

6.37 NST submitted offers for IL for both GXPs until 2013, after which it only submitted offers for the KAW0113 GXP. NST also decreased its offers at this node from 2013 onwards.[8] Offers were the same for six second (Fast instantaneous reserve) and sixty second reserves (Sustained instantaneous reserve).

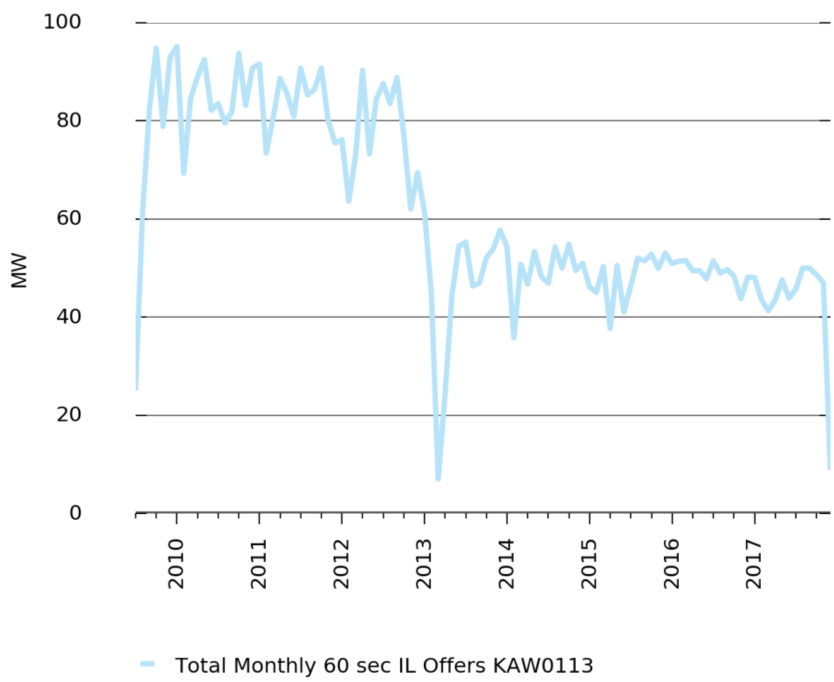
Figure 9: Interruptible load offers KAW0112 node



Source: EA

Figure 10: Interruptible load offers KAW0113 node

[8] NST also offers IL at the KAW0111 node.



Source: EA

NST uses DD bids to avoid high RCPD charges, but it appears the DD scheme does not make this easier

6.38 Transmission pricing ensures that Transpower can recover the full cost of its assets. Transmission pricing is made up of connection charges, interconnection charges, and high voltage direct current (HVDC) charges.

6.39 Connection charges recover part of Transpower's AC revenue by reference to the cost of providing connection assets. Interconnection charges recover the remainder of Transpower's AC revenue.

6.40 Transmission customers are allocated interconnection charges based on their contribution to Regional Coincident Peak Demand (RCPD). RCPD is calculated by taking the 100 trading periods when demand was the highest over the capacity measurement period of 1 September to 31 August for each of four regions.

6.41 The RCPD method incentivises directly connected users to respond to regional peak demand. They are strongly incentivised to minimise their contributions to peak load as this will reduce their allocated interconnection charges. This is especially the case since interconnection charges can be a lot higher than energy prices.

6.42 NST has been very successful at moving load away from RCPD periods. NST demand was higher on average during non-peak periods than during the 100 peak periods used to calculate RCPD (see Table 4) for the two complete capacity measurement periods for RCPD calculations during which NST has been participating in the DD scheme.

6.43 Both Winstone Pulp International (who take electricity from the grid at the TNG0111 node) and Pan Pac Forest Products Limited (who take electricity from the grid at the WHI0111 node) also reduced their demand during the 100 peak periods used to calculate RCPD. From 1 September 2016 to 31 August 2017, Winstone Pulp reduced demand in the 100 peak periods by an average of 22.9 per cent, while Pan Pac reduced by 44.8 per cent on average. While NST reduced demand by a greater percentage than these other two users (reducing demand by 83.1 per cent on average at the KAW0113 node over the same period), this is consistent with its reductions before it took up the DD scheme.

6.44 As well as reducing demand during peak periods, NST also changes its DD bids. As well as increasing the minimum bid price, it also reduces the amount of trading periods in which its bids are dispatchable (see Table 5 and Table 6). At the KAW0113 node, NST also substantially reduces the quantity that it bids for over peak periods (see Table 7).

Table 4: Demand (metered, mv90) during peak and off-peak periods

Period	GXP (MW)			
	KAW0112[9]	***KAW0113[10]***	***TNG0111***	***WHI0111***
1 September 2012 – 31 August 2013				
Off-peak	19.27	50.18		
Peak	18.92	11.96		
Per cent reduction in demand	1.8%	76.2%		
1 September 2013 – 31 August 2014				
Off-peak	32.48	43.05		
Peak	37.48	7.47		
Per cent reduction in demand	-15.4%	82.6%		
1 September 2015 – 31 August 2016				
Off-peak	36.47	41.57	27.58	59.09
Peak	37.08	8.28	25.53	34.62
Per cent reduction in demand	-1.7%	80.1%	7.5%	41.4%
1 September 2016 – 31 August 2017				

9 Demand for the KAW0112 node is all demand at this node for the first 3 periods in the table, but only for the DCLS for the 4th period in trading periods nominated as dispatchable (there is no demand for the DCLS at this node prior to this period). This node has embedded generation, but this negative demand is ignored in metered demand.

10 Demand for the KAW0113 node is all demand at this node for the first 2 periods in the table (prior to DD), then for the DCLS for the second two periods (in trading periods nominated as dispatchable).

Period	GXP (MW)			
	KAW0112[9]	***KAW0113***[10]	***TNG0111***	***WHI0111***
Off-peak	33.06	37.38	27.34	57.89
Peak	23.45	6.31	21.08	31.93
Per cent reduction in demand	29.1%	83.1%	22.9%	44.8%

Table 5: Minimum bid price during peak and off-peak periods

Period	GXP (median minimum bid price)	
	KAW0112	***KAW0113***
1 September 2015 – 31 August 2016		
Off-peak	n/a ($50000)	$100
Peak	n/a ($50000)	$100
1 September 2016 – 31 August 2017		
Off-peak	$400	$100
Peak	$600	$175

Table 6: Per cent of trading periods that were dispatchable during peak and off-peak periods

Period	GXP (per cent of trading periods that were dispatchable)	
	KAW0112	***KAW0113***
1 September 2015 – 31 August 2016		
Off-peak	0%	92%
Peak	0%	29%
1 September 2016 – 31 August 2017		
Off-peak	93%	84%
Peak	68%	19%

Table 7: Total bid quantity during peak and off-peak periods

Period	GXP (mean total MW bid)	
	KAW0112	***KAW0113***
1 September 2015 – 31 August 2016		
Off-peak	37.27	43.81
Peak	38.73	12.34
1 September 2016 – 31 August 2017		
Off-peak	35.33	40.34
Peak	33.81	10.65

7 We looked at why others have not joined the scheme

7.1 Any industrial user assessing the scheme will weigh up the real and perceived risks and costs against the potential for economic gain through favourable pricing or incentives. For this review we asked three large industrial users and one aggregator their reason(s) for not joining the DD scheme.

7.2 Ellis and Managan (2014)[11] discuss how potential participants evaluate three attributes of any demand response scheme:

(a) attractiveness of payments and incentives

(b) level of complexity

(c) ability to supply the resource required.

7.3 These three attributes have all contributed to the lack of participation in the scheme, as assessed through our conversations with potential scheme entrants.

Attractiveness of payments and incentives

7.4 For the DD scheme, the payments and incentives of the scheme for large industrial users are price certainty and constrained on and off payments (while the CBA also listed better prices as a benefit, this benefit is not simple and certain enough for users to accurately forecast the benefit to them and it may not accrue to individual firms). In conversations with us, users indicated that reduced price uncertainty is not a big enough benefit to justify the time and effort needed for participating. In its submission to the original DD design consultation, Meridian pointed out there is no evidence to suggest the lack of price certainty is the core barrier to demand-side participation. This seems to have been confirmed by the lack of take-up of the scheme. Meridian suggested instead the lack of production flexibility, inability to meet SO requirements, and a lack of interest in engaging in non-core business activity may be far greater barriers to participation.

[11] Ellis, John, and Managan, Katrina (2014), *Increasing Demand for Demand Response*, Issue Brief, Institute for building efficiency.

7.5 It seems the benefit of constrained on and off payments do not outweigh the costs of compliance. Those we talked to saw the need to comply with dispatch instructions as being undesirable. Some of the potential participants we talked to mentioned they may not always want to turn off when they are dispatched off. They would like to keep control over their production processes and when they reduce load, irrespective of process conditions. They may also have to turn off for a longer period of time than is desirable, since DD dispatch instructions are based on half-hourly trading periods. With IL—an alternative way for load to participate in the wholesale electricity market—plant only needs to turn off for 5 or 10 minutes. However, with DD, they must turn off for a longer time period and the time period is uncertain (ie, it could be over more than one trading period).[12] Although NST uses nominated non-dispatch bids to manage this to a certain extent, none of the users that we talked to bought this up as a solution to the problem.

7.6 The rules that participants need to adhere to for bidding are tighter under the DD scheme than under DSBF at non-conforming nodes. For example, for non-dispatch bids (ie, bids at non-conforming GXPs that are not part of DD) a purchaser must immediately revise its bid if it expects the quantity of electricity its likely to purchase will change by the lesser of 20MW or 20 per cent of the bid quantity (with a minimum of 5MW). For DD participants these figures are 10MW and 10 per cent respectively. One potential participant mentioned these tighter rules as a possible disincentive to joining the scheme.

Level of complexity

7.7 The complexity of the scheme has also been a barrier to participation. Potential participants feel that they face large overheads due to the complexity of the scheme. The industrial users we spoke to did not have dedicated staff to manage electricity use. They say the complexity of the scheme makes it difficult for staff trained in plant operation to pick up the necessary skills. Operationally it would be very challenging to add DD to an already busy schedule. Without a dedicated electricity manager, operating desks could be unmanned for reasonable periods of time if staff need to attend to plant.

7.8 To make it easier for users to participate, the day-to-day management of demand may need to follow a simpler approach. This could perhaps be achieved through some sort of technical assistance, such as enabling co-ordination with existing load management systems. Participants could use software with an integrated user interface for all of their energy management tasks. Ellis and Managan (2014) discuss how financial incentives to install enabling technologies can help lower participation costs for users and make demand response programs more attractive. It may also allow individual equipment to be tracked and controlled, allowing more targeted demand curtailment within a customer's load.

Ability to supply the resource required

7.9 Production processes may not lend themselves well to being turned on and off. For example, the steel mill we spoke to mentioned that if it had its load curtailed, it could divert concentrate into a hopper. However, the hopper has a limited capacity. Therefore, if the hopper was already full when the load curtailment occurred, the mill would need to

[12] This is not strictly true, ie, tripped IL must stay tripped until restoration instructions are issued by the system operator, but the target for restoration is within 15 minutes (although has exceeded this). However, the expectation by the industrial users we talked to was that the period of time they would be dispatched off for would be shorter for IL than for DD, and more certain.

dump some of the concentrate which was already in the hopper, which is not ideal. In other words, electricity usage is only part of the equation for production dynamics.

7.10 Manufacturers we spoke to had concerns about the impact of load curtailment on their processes. They indicated that they may be able to cope with short interruptions but not longer ones. They also mentioned concerns about adequate advance notice (this may become more of an issue if RTP is implemented).

7.11 While many submissions to the modified DD design discussed co-optimisation between IL and DD as a key benefit of the original design, none of the four users we talked to mentioned the lack of co-optimisation as a barrier to participating. One user had concerns about being able to offer IL and DD at the same time, but concluded this was possible (ie, if there was an event requiring IL, they could bona fide out of DD and vice versa). However, making it easier to co-ordinate managing both (along with other energy management practices) could encourage increased participation in the scheme (as mentioned above).

7.12 Finally, one potential participant mentioned the cost of metering has also discouraged it signing up some smaller load to the scheme.

8 Non-participants have more flexibility and face only a small cost associated with price uncertainty

8.1 The NRSS price is used to generate dispatch instructions. The NRSS starts solving about three minutes after the start of each trading period, and results are normally available within a further two minutes. The system operator issues dispatch instructions for the next trading period based on this result. Thus, the system operator normally issues dispatch instructions applying to a trading period to the DCLS around 25 minutes before the start of that trading period.

8.2 The original DD proposal based dispatch off the RTD schedule. The RTD schedule runs every 5 minutes, so under the original design, the system operator could update dispatch instructions every 5 minutes. However, as discussed above, the modified design results in the system operator issuing dispatch instructions 25 minutes before the trading period.

8.3 All participants can see ex-post 5-minute prices (the real-time pricing (RTP) schedule, published at the end of every 5-minute period). This means that under the modified design, dispatch instructions are based on older information than the RTP information that other purchasers may use for voluntary demand response. While any changes in final price may be reflected through constrained on and constrained off payments to the DD participant providing increased certainty, voluntary demand response can be more flexible. That is, large industrial users of electricity who do not participate in the DD scheme face more uncertainty (of the difference between the RTP price and the final price) but can also be more flexible.[13]

8.4 Large industrial users already practice voluntary demand response by adjusting demand to avoid interconnection charges. All users can see both the NRSS and RTP schedules. Ninety eight per cent of the time, the NRSS price at the two nodes where NST consumes electricity has been within +/- $30/MWh of the final price (since NST started participating

[13] It should be noted however that DD improves the accuracy of the RTP forecast prices by including DD bids, and would be further improved if there were more participants in the DD scheme.

in DD). The final price has been a maximum of $335 and $337 (respectively for each node) greater than the NRSS price. This is similar at the TNG0111 and WHI0111 nodes (two nodes with other large industrial users, maximum differences when the final price was greater than the NRSS price were $358/MWh and $342/MWh respectively). So while there is some uncertainty around final pricing for electricity, 98 per cent of the time this uncertainty is low cost for the user.

8.5 Additionally, large industrial consumers should be able to access risk management instruments such as forward contracts or commercial fixed price variable volume contracts. These sorts of market instruments mean these large consumers are less exposed to spot prices and therefore perhaps less likely to engage in demand response.

9 Real time pricing would affect the future of DD

9.1 The Authority is developing its proposal to determine and publish final prices for the spot market in real-time – we call this 'real-time pricing' (RTP). While the Authority has not yet decided to proceed, we assume for this analysis that RTP will be implemented.

9.2 Incorporating the existing DD scheme within RTP is not straightforward, so the Authority has proposed the DD scheme would change if RTP is implemented.

9.3 Dispatchable demand would be dispatched from the dispatch schedule rather than the NRSS. This means that DD participants would be dispatched every 5 minutes instead of every half hour. As the RTP consultation paper discusses,[14] this could result in DD participants being exposed to yo-yo dispatch instructions. However, the Authority expects this to be rare, and DD participants could use the ability to rebid within a trading period to avoid being on the margin and therefore subject to yo-yo dispatch.

9.4 A shorter dispatch time could make participation more or less attractive to different industrial users depending on production processes. Dispatching based on the 5-minute dispatch schedule will mean the lead time on dispatch instructions will greatly decrease compared to the current set-up. Some production processes may not allow response within 5 minutes. However, other production processes may be more amenable to shorter load curtailment durations. Although as the proposal currently stands, it may not overcome the uncertainty around the time period that production processes may be dispatched-off. Participants may be allowed to re-bid, but as with current arrangements they may not want to commit resources to do this.

9.5 Under the RTP proposal, participants in the DD scheme would no longer need to provide metering data to the pricing manager the next day (so overheads would be reduced, although DD metering for monthly settlement would still be needed). Also, Transpower expects to complete their Dispatch Service Enhancement project before RTP. This will remove the requirement for participants to use GENCO for receiving and acknowledging dispatch instructions (currently needed if dispatch instructions are based on the RTD schedule). Transpower asserts that 'This will be a stepping stone towards greater participation in a market that is moving fast with the uptake of new technology, while at the same time providing a more flexible and secure dispatch management service'.[15]

9.6 As part of the RTP proposal The Authority is proposing a simplified form of DD for smaller electricity users, called 'dispatch-lite' (D-lite). Participants would be able to bid

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14 Real-time pricing proposal consultation paper, available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609

15 https://www.transpower.co.nz/system-operator/so-projects/dispatch-service-enhancement-project

their controllable load into market schedules but they would receive dispatch 'notifications' from the SO rather than dispatch 'instructions'. That is, they would have the option of not complying with the 'notification', provided they communicated this swiftly to the SO and did not make this a habit. They would have less onerous compliance obligations, but would not be eligible for constrained on and off payments.

9.7 The Authority is committed to encouraging increased participation in DD. The Authority's Annual Report[16] states on page 37 that the Authority will work towards 'encouraging the efficient use of dispatchable demand as a means to allow consumers to participate more directly in the spot market through:

(a) ensuring the correct incentives in the spot market for DD constrained-on/off payments

(b) potentially enabling an aggregator to aggregate load over several GXPs and several retailers'

9.8 The Authority's work programme includes a project looking at enabling aggregators to aggregate load over several conforming GXPs and several retailers. This would involve an expansion of the DD scheme.

9.9 Additionally, it is on The Authority's work programme to update the Demand response guiding regulatory principles. In the 2015 paper, it states that 'unnecessary technology and compliance requirements on demand response should be avoided'.[17]

10 We analysed the expected benefits of the scheme

Our approach and methodology

10.1 Our approach to post implementation reviews, in descending order of preference, is to:

(a) estimate the likely benefits and costs achieved and/or test whether key indicators that were directly expressed in the cost benefit analysis (CBA) have changed

(b) measure changes in other indicators mentioned in the problem definition or policy objective.

10.2 Our approach is constrained by the availability and quality of data. We are also constrained by the environment and other market changes, which may make it too difficult to disentangle effects of this initiative versus other concurrent market changes or events.

The Authority identified and quantified the benefits when the Code was amended

10.3 The consultation paper *Dispatchable Demand*[18] provided estimates of the costs and benefits based on different scenarios of uptake of the scheme. Subsequently, the Authority updated these costs and benefits in the *Modified design of dispatchable*

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16 https://www.ea.govt.nz/about-us/strategic-planning-and-reporting/annual-report/

17 https://www.ea.govt.nz/development/work-programme/evolving-tech-business/demand-response/development/demand-response-guiding-regulatory-principles/

18 Published on 13 July 2011 and available here: http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/dispatchable-demand/consultations/#c7563

demand consultation paper.[19] These estimates yielded a net present value (NPV) of $2.4 million under the original design, and $1.0 million under the modified design, over a period of 8 years. The Authority based this on the proposal initially attracting participation from one or two major electricity users. The expected total implementation costs under the modified design were $4.65m.

10.4 There were six classes of benefits identified in the original consultation paper—subsequently reduced to four under the modified design. We discuss these below (as discussed in the consultation papers). The estimated quantitative amount for each benefit is shown in Table 8.

10.5 *Better short term production and consumption decisions from better pricing* is based on DD leading to better information being used in the final pricing schedule, and therefore final prices being of a higher quality. In particular, when market conditions are tight and prices are high, there may not be many generator offers at the "high end" of the offer curve. Dispatch bids may, by populating this region of the market with more information about the marginal benefit of consumption, better signal the marginal system cost of meeting additional load. This could lead to more robust and precise pricing outcomes during tight supply situations.

10.6 For example, if 20MW of dispatched-off demand replaced 20MW of high-end generation over 25 hours of tight supply, and we assume the savings amount to $500/MWh, the cost savings would amount to $250,000 (20MW * 25 hours * $500/MWh).[20]

10.7 *More efficient demand-side response to changing conditions within a trading period.* The Authority listed this benefit in the original consultation paper but it no longer applies under the modified design. Under the original design, a DCLS would have received a new dispatch instruction if market conditions changed within a trading period, such as the unexpected withdrawal of a generator. Under the modified design, the system operator issues dispatch instructions from the NRSS schedule, which is only run **before** a trading period. This means that the system operator cannot issue updated dispatch instructions within a trading period.

10.8 *Better management of security issues.* This benefit would arise from having a greater proportion of the industry's physical assets (both demand-side and supply-side) within the "dispatch envelope" rather than outside it. For example, before the DD scheme, managing flow on transmission lines was restricted by dispatching generation only (eg, dispatching more downstream generation and less upstream generation so the flow does not exceed some maximum value). Or, if no downstream generation was available, forced load shedding, at an estimated VoLL (value of lost load) cost of around $10,000/MWh. However, the DD scheme provides an additional option. Downstream demand could be dispatched down (if that provides greater net benefits than dispatching generation). This places less pressure on the transmission lines and avoids potential involuntary disconnection. When the Authority modified the DD scheme, this benefit was reduced because demand would no longer be dispatched on a 5-minute basis from the RTD schedule.

[19] Published 23 July 2013 and available here: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/dispatchable-demand/consultations/#c7563

[20] Example from *Dispatchable Demand* consultation paper

10.9 *Better coordination between electricity usage and IL provision.* Under the original proposal, a DCLS owner at a non-conforming GXP could submit an IL offer which the system operator could co-optimise against the dispatch bid. This means that the market scheduling and dispatch optimisation programme (SPD) would be able to dispatch the optimal combination of electricity usage and IL. If the system was short of instantaneous reserves, a DCLS could be dispatched to use more electricity so it could make greater quantities of IL available. However, under the modified design, the Authority changed DD to be dispatched from the NRSS schedule, rather than the RTD schedule used for IL. This means that under the modified design, the system operator can no longer co-optimise DD and IL.

10.10 *Better investment decisions from better pricing.* This is similar to the static benefit described in paragraph 10.5, but relates to longer-term investment decisions (eg, less investment in costly peaking/last resort generation).

10.11 *More price responsive demand (especially over the longer term) attracted by constrained on and constrained off payments.* Over time, major electricity users may migrate towards increased controllability and flexibility to allow them to respond to electricity market conditions. These major electricity users would be motivated by the benefit they would get of accessing constrained on and constrained off payments through participating in the scheme.[21] Substantial system benefits could arise as more electricity users put in place the technology, and adopt systems and behaviours that result in greater demand response. Any increase in the flexibility of the demand side in responding to wholesale spot market conditions could deliver a significant system benefit.

10.12 Table 8 provides an overview of the predicted changes from the scheme,[22] the expected results (based on the modified DD design), and an assessment of our ability to measure these.

Table 8: The anticipated benefits of the DD scheme

Note	Measure	Direct assessment made in CBA?	Expected result* ($/year)	Ability to measure over the review period	Captured in this review?
	Static benefits				
a	Better short term production and consumption decisions from better pricing	Y	325,000	High	Y

21 Note that these payments constitute wealth transfers (the costs are socialized across all loads), so do not directly increase efficiency. They do however provide insurance for DD participants against uneconomic decisions, increasing the likelihood that users will participate in the scheme, and therefore also increasing the number of economic DD dispatch decisions.

22 Sourced from the Authority's consultation paper *Consultation Paper – Modified design of dispatchable demand* available here: *http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/dispatchable-demand/consultations/#c7563*

Note	Measure	Direct assessment made in CBA?	Expected result* ($/year)	Ability to measure over the review period	Captured in this review?
c	Better management of security issues	Y	50,000	High	Y
	Dynamic benefits				
e	Better investment decisions from better pricing	Y	325,000	Low	Y
f	More price responsive demand (especially over the longer term) attracted by constrained on and constrained off payments	Y	390,000	Medium	Y

*Based on participation from 1 to 2 major users.

We considered each of the expected benefits

Whether the longer-term benefits of the DD scheme may continue to accrue post-RTP implementation is uncertain

10.13 Since we assume that RTP will proceed with implementation closely aligning to the proposal, we also assume DD would undergo a change to both the frequency and method of receipt of dispatch instructions.

10.14 However, much of the investment in processes and systems for the DD scheme will remain the same under RTP. It is therefore unclear whether our assessment below of the longer-term benefits should be in isolation from RTP (effectively limiting the life-time of these benefits), or whether the benefits can still be realised and attributed to DD post-RTP implementation. We discuss a qualitative assessment of this for each longer-term benefit further in the respective sections below.

Better short term production and consumption decisions from better pricing

10.15 We use simulations to assess benefit (a) using vSPD (vectorised Scheduling, Pricing and Dispatch). vSPD is a precise replica of SPD, and is based on the published SPD formulation. SPD is a model run by the system operator which solves the security constrained economic dispatch of electricity. It takes offered generation and reserve, and dispatches it to meet demand (bids or forecast) (ie, supply equals demand) in a way which maximises the gross economic benefits to purchasers less the total cost of generation and reserve, while satisfying the many constraints on the system. That is, it determines the level of generation (and demand) and the price at each node, every half hour.

10.16 We ran and compared two scenarios using vSPD:

(a) the first scenario (the factual or "DD") represents what actually happened under the DD regime in terms of consumption (not price, as discussed below). NST's DD bids were forced to clear at the actual historical demand level (ie, irrespective of cleared bids and dispatch instructions), so sometimes NST may have consumed more or less than the dispatch instructions.

(b) the second scenario (the counterfactual or "no DD") represents what would have happened without the DD regime. In this case NST's DD bids were forced to fully clear as if it had not been dispatched off at all (ie, were not participating in the DD scheme).

10.17 For the simulations, we assume the real (and unobserved) demand curve is the same in both scenarios.[23] Note that in scenario two, all demand bids were forced to clear (ie, consume) even when the generation cost exceeded the value of the consumption (as defined by NST's bids).

Estimating price changes

10.18 For comparing prices, we compared final prices to the prices resulting from the no DD scenario simulations (excluding periods where the simulations resulted in infeasibilities). We did not use the price from the DD scenario simulations because these prices are based on NST's actual consumption, which is not what final prices are based on. In practice, final prices are calculated using NST's bids. Note that by using the prices arising under the no DD scenario simulations we assume the total quantity bid by NST is an accurate reflection of what it would have consumed had there been no DD scheme. Although we argue in section 7 that NST's bid curve may not be an accurate reflection of its actual demand curve, we think the **total** bid quantity indicates the total electricity NST may have consumed if there had been no DD scheme. This assumes that NST would not have practiced demand reduction otherwise, which we know is not true. The difference in price is therefore likely to be an upper bound of the price difference.

10.19 Final prices in periods when NST was dispatched off were on average \$1.90 /MWh and \$2.55/MWh lower than prices from the no DD scenario simulations at the KAW0112 and KAW0113 nodes respectively. Over *all* nodes, the mean price difference (in periods when NST was dispatched off) was \$1.88/MWh. From section 7 we know there were 175 periods (scenario C) when NST was dispatched off. So while the price difference is reasonably substantial, due to the low number of periods where the price is affected, the average change over all periods is small. If we average the price difference over all periods between 20 November 2014 and 6 December 2017, the average difference is 0.7 cents/MWh.

Estimating the value of better production and consumption decisions

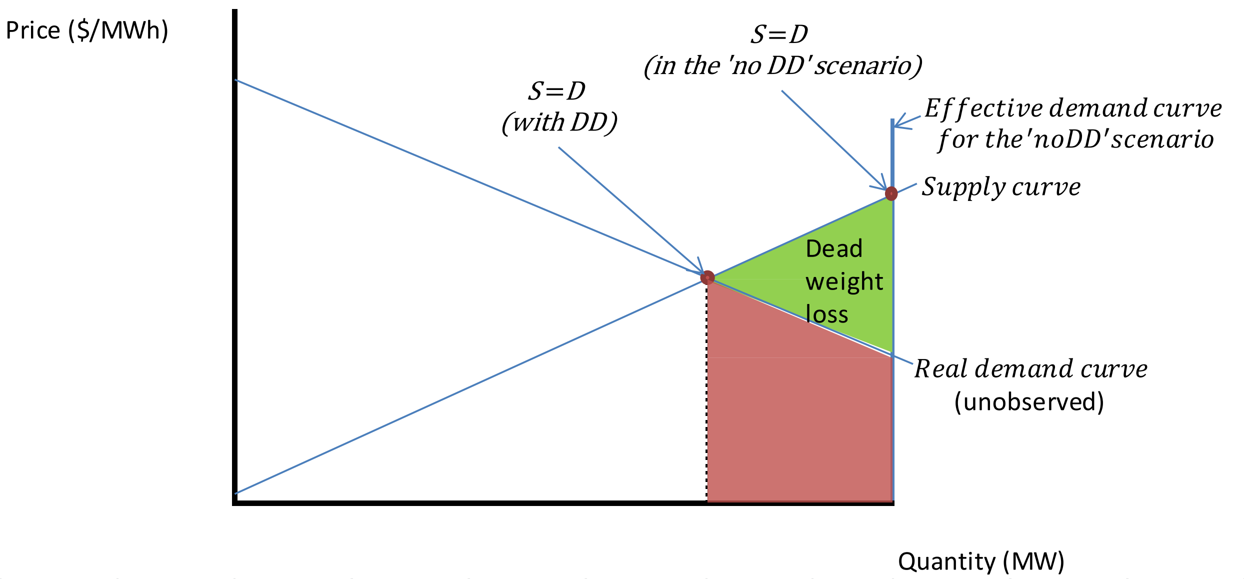
10.20 In theory, the value (net welfare gain) of better production and consumption decisions is represented by the green triangle in Figure 11 below (the deadweight loss which results

[23] Aside from changing the cleared quantity of dispatchable demand, the simulations are run all else being equal. This assumes that there is no countervailing response from other market participants. That is, all generation and reserve offers are unchanged, and other demand remains unchanged.

when more load is dispatched than is efficient in the no DD scenario). However, there are difficulties in estimating this because in reality NST's observed demand does not match its bids. This means that we cannot infer the demand curve from NST's bids, and thus we cannot calculate the triangle. We can however calculate the area under the supply curve in both scenarios, the difference of which is represented by the green triangle plus the red shaded area. This total area represents the reduction in cost due to the use of the DD scheme. As this area will always be bigger than the net welfare gain (the green triangle), we are effectively estimating an upper bound for the welfare gain.

10.21 Overall, based on our simulations we estimate the area of the green triangle in Figure 11 (the net welfare gain) has been no more than approximately $110,000 per annum (compared to $325,000 per annum in the expected benefits in Table 8).

Figure 11: Net welfare gain and system cost



Better management of security issues

10.22 While this benefit remained under the modified design (as there is still an increased proportion of the industry's physical assets available within the "dispatch envelope"), the Authority reduced this benefit because demand would no longer be dispatched on a 5-minute basis.

10.23 The scheme's contribution to **transmission** security issues is not clear. Because the scheme bases compliance on average demand for each trading period, a DCLS required to decrease demand by 50MW could decide to do nothing for 15 minutes, then reduce demand by 100MW for 15 minutes. This would improve any security issues associated with generation capacity during the time when the DCLS reduced demand. However, the transmission security situation may not improve (depending on where the DCLS is in the grid) since supply side dispatch is every 5 minutes. For example, consider the situation where the system operator is dispatching the system to ensure that a particular transmission line does not exceed some maximum value. In this situation, the 15 minute period when the DCLS does not reduce demand (when the system operator instructed it to do so) will impact the optimal solution for security the system operator arrived at, if (for example) the DCLS is located at a point in the grid that is importing over a constrained line. The modified DD design consultation paper stated that, for compliance, '…there may be a greater "margin of error" allowed than under the original DD design because DD is not being relied upon for security'. The Authority decreased the dollar amount associated with this benefit from $100,000 per year in the original design to $50,000 per year in the modified design. We could not measure this benefit using the simulations.

10.24 Note the only participant of the scheme thus far is located at a point in the grid which tends to export. This means that transmission issues at the two nodes where DD operates tend to supress prices rather than increase them. The DD scheme contributes to managing security issues through dispatching off the DD participants (when prices increase above DD bid prices). This suggests that with only NST participating, DD has not contributed to managing transmission security issues over the three years in which it has been operating.

Better investment decisions from better pricing

10.25 While there has been a small decrease in prices due to DD of $2/MWh—for all nodes over the periods when DD was dispatched off—these decreases were only realised for 175 trading periods. Our view is that these results do not seem substantial enough to encourage a change in investment.

10.26 Since pricing will change substantively if the Authority implements RTP (that is, forecast prices should be of higher quality), our view is that this benefit would need to be realised before the Authority implements RTP (to be able to assign the benefit to the current DD scheme).

10.27 However, the existence of DD and the prospect of more demand side participation under RTP may lead to more investment decisions having demand side considerations factored into them in the future.

More price responsive demand

10.28 In the three years DD has been running, only one participant has joined the scheme. Other large industrial users we talked to appeared to have no plans to join the scheme as it currently stands. Additionally, the current participant was already practicing demand response before it joined the scheme.

10.29 Our view is that this benefit has not been realised thus far. We are unsure whether introducing RTP (with changes to the DD scheme) would change this. However, it seems unlikely given the proposed changes to the DD scheme would be unlikely to increase constrained on and off payments, and RTP would improve forecast prices.

11 Conclusion and recommendation

11.1 Our view is the scheme so far is unlikely to have accrued benefits over and above its implementation costs, and will most likely require further refinement to increase participation (and greater benefits) in the future.

11.2 The scheme has had a small impact on prices (as found through simulations). The scheme lowered prices by approximately $2/MWh over the 175 trading periods when

NST was dispatched off and their load was closer to the dispatch quantity than to their bid quantity.

11.3 NST has also mentioned that, while the modified DD design does not allow for co-optimisation of IL and DD, co-ordination of bids for IL and DD is easier with participation in the DD scheme.

11.4 NST has been successful at reducing load to avoid interconnection charges, both before and after it took up the DD scheme. While it has made use of different options under the DD scheme to assist with this load reduction, there is no evidence that participation in the DD scheme is contributing to this success. The options it has used include:

(a) submitting non-dispatch bids

(b) submitting bids with a lower quantity

(c) submitting bids with a higher price.

11.5 Other users have not been enticed to join the DD scheme. Feedback from all the large industrial users we talked to was that the benefits of price certainty and constrained on and off payments do not outweigh the perceived costs of participating. The perceived costs include:

(a) a lack of control over production processes

(b) compliance costs because of the complexity of the scheme

(c) concern about what impact load curtailment and the duration of load curtailment will have on production processes.

11.6 Other findings include:

(a) The code change to bring constrained on and off payments in line with their economic purpose was successful.

(b) There is no evidence to suggest that yo-yo dispatch is a problem for NST, given that it can submit nominated non-dispatch bids.

(c) There is no evidence that final prices have ‘shadowed’ DD bid prices.

11.7 To design an effective demand response program, it is essential to understand prospective participants business and energy needs. Sensitivity to different users’ concerns and ways of using electricity helps inform demand response design. Reduced complexity and compliance, both real and perceived, may go a long way towards increasing participation. As Ellis and Managan (2014, page 7) point out ‘In order to capture enrolment of demand resources [by large industrial users], it is essential to offer timing flexibility and leave the majority of control in the hands of the customer’. The current DD implementation allows for greater flexibility and control for users than the proposed DD scheme under RTP, but still has not attracted more participants to join.

11.8 One such avenue for increased control over production processes within the DD scheme is the option to submit non-dispatch bids. NST sometimes uses this option to avoid yo-yo dispatch. It could also perhaps be used (and may already be used by NST because of operational constraints on equipment) to enable increased control over the duration of load curtailment (alongside re-bidding) if dispatch of demand changes to be every five minutes under RTP. The advantages of this option for DD may need exploration and discussion with potential participants within the Authority’s development of RTP.

11.9 If the Authority proceeds with developing RTP, it should carefully evaluate the D-lite scheme to determine whether it would add anything over voluntary demand response. RTP should result in better quality prices regardless of D-lite or DD participation. Industrial users who already see little benefit from increased price certainty may find this benefit even further reduced. Additionally, it is uncertain whether the lower compliance obligations of the D-lite scheme would make this scheme more attractive to users.

11.10 Further enhancements to the DD scheme could improve participation in the near future. However, the Authority considers it more appropriate to prioritise effort into progressing the real-time pricing project. Real-time pricing is expected to deliver greater demand-side participation, as well as a range of other benefits.